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March 14, 2014

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-13-21
Capacity Deficiency Period Utilized in SAR Methodology – Idaho Power Company's Reply Comments

Dear Ms. Jewell:

Enclosed for filing in the above matter are an original and seven (7) copies of Idaho Power Company's Reply Comments.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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Attorneys for Idaho Power Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF ITS CAPACITY DEFICIENCY PERIOD TO BE UTILIZED IN THE COMPANY'S SAR METHODOLOGY.	CASE NO. IPC-E-13-21 IDAHO POWER COMPANY'S REPLY COMMENTS

Idaho Power Company ("Idaho Power" or "Company") respectfully submits the following Reply Comments in response to Comments filed by the Idaho Public Utilities Commission ("Commission") Staff ("Staff") on February 23, 2014.

I. PROCEDURAL HISTORY AND INTRODUCTION

In December 2012, the Commission directed that this case be initiated outside of the Integrated Resource Plan ("IRP") filing for the establishment of the capacity deficiency period to be utilized in the surrogate avoided resource ("SAR") avoided cost rate methodology:

> [W]e find it reasonable and fair to subject each utility's determination of capacity deficiency to further scrutiny. Therefore, when a utility submits its Integrated Resource

> Plan to the Commission, a case shall be initiated to determine the capacity deficiency to be utilized in the SAR Methodology. The capacity deficiency determined through the IRP planning process will be the starting point, and will be presumed to be correct subject to the outcome of the proceeding.

Order No. 32697, p. 23. The Commission also directed in that Order that inputs from the Company's IRP will remain fixed between IRP cycles, with the exception of the load forecast and the natural gas forecast—which is to be updated annually by October 15 of each year. Order No. 32697, p. 22; Order No. 32802. The Commission also directed that Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts that have terminated or expired, as well as any new long-term contracts that have been signed, be included in the utility's load and resource balance. Order No. 32697, p. 22.

Idaho Power filed its 2013 IRP on June 28, 2013.[1] On October 15, 2013, the Company filed its updates to the IRP's avoided cost rate inputs, including an updated load forecast, updated natural gas forecast, and an updated list of new and terminated PURPA contracts and long-term power purchase agreements. The Commission subsequently approved these updates in Order No. 32941. Idaho Power filed its Application in this case on November 4, 2013, seeking an update to the capacity deficiencies identified in the 2013 IRP for purposes of avoided cost rate determinations with a first deficit occurring in July 2021.

On February 28, 2014, Staff filed Comments recommending a first deficit year of 2016. Idaho Power now files its Reply Comments addressing Staff's criticisms and assumptions and reiterating its request for establishment of a first capacity deficit occurring in July 2021 for purposes of avoided cost rate determinations.

[1] Idaho Power's 2013 IRP was recently accepted by the Commission on February 24, 2014. Order No. 32980.

II. COMMENTS

Idaho Power set forth three identified capacity deficiency positions in its Application for this case: (1) the capacity deficiencies identified in the 2013 IRP; (2) the 2013 IRP capacity deficiencies updated to include the updated load forecast, natural gas forecast, and new and terminated contracts from Case No. IPC-E-13-18; and (3) the updated 2013 IRP capacity deficiencies, including up to 440 megawatts ("MW") of demand response ("DR") from the settlement agreement ("Settlement Agreement") in Case No. IPC-E-13-14.

Staff was highly critical of, and disagreed with, the Company's inclusion of up to 440 MW of DR. Instead, Staff recommended including only 170 MW of DR for determining the capacity deficiency for avoided cost rate pricing. Staff Comments, p. 8. Staff stated:

> Idaho Power's inclusion of demand response in its load resource balance assumes it can reliably and immediately provide 440 MW continually throughout the entire 20-year planning period. Staff believes this contradicts the basis of the Commission-approved settlement agreement, the likely effect of the program modifications included in the settlement, and is not justified by the Company's responses to discovery in this case. Staff maintains that the most reasonable estimate of the capacity provided by Idaho Power's demand response portfolio is 170 MW.

Staff Comments, p. 4.

As explained below, it is Staff's arbitrary limitation of DR capacity to 170 MW that "contradicts the basis" of the Settlement Agreement, is inconsistent with the Settlement Agreement and the accepted 2013 IRP, and results in an overpayment of capacity in the PURPA avoided cost rate to the detriment of customers.

A. Staff's Assumption Limiting DR Capacity to Only 170 MW Is Not Consistent with the Settlement Agreement.

Staff criticizes the Company for including 440 MW of DR in its Peak-Hour Surplus/Deficit Charts. Staff contends that the inclusion of 440 MW is inconsistent with the outcome of the Settlement Agreement entered into in Case No. IPC-E-13-14, approved by the Commission in Order No. 32923. Staff contends that the appropriate estimate of capacity to be achieved after the Settlement Agreement is 170 MW. Staff's position incorrectly equates the value (the amount the Company can spend on demand response) with the capacity (the amount of demand response the Company is required to accept). The Settlement Agreement states:

> The Company ***must***:
>
> i. ***Use*** existing demand response resources when possible. This includes using, to the extent possible, current demand response equipment owned or available to Idaho Power and participating demand response customers, which currently represents ***approximately 400 megawatts ("MW")*** of potential demand response capacity
>
> . . .
>
> vi. ***Calculate*** the avoided cost used for demand response by using the avoided capacity ***cost of a 170 MW*** single cycle combustion turbine ("SCCT") multiplied by the effective load carrying capacity ("ELCC"), measured over 20 years, plus the corresponding deferred energy savings for 60 program hours.

Case No. IPC-E-13-14, Settlement Agreement, p. 3 (emphasis added).

In the DR workshops leading up to the Settlement Agreement, the participants expressed a desire to preserve customer participation in and infrastructure used for Idaho Power's DR programs for the long-term, and acknowledged that this meant incurring DR costs even in years when the IRP did not demonstrate a need for such

costs. The participants ultimately justified the value of incurring costs in such years by reasoning that, if demand response were not available, the Company would likely choose to build a 170 MW simple-cycle combustion turbine ("SCCT"). The participants agreed to use the value of this 170 MW SCCT "multiplied by the effective load carrying capacity, measured over twenty years, plus the corresponding deferred energy savings" as the minimum avoided cost of DR. Settlement Agreement, p. 4. This value is to be used "even in years when the IRP shows no peak-hour capacity deficit" and "will be updated with each IRP based on changes that include, but are not limited to need, capital cost, or financial assumptions." Settlement Agreement, pp. 4-5.

The value of DR does not equate to the amount of DR capacity the Company is required to accept and may acquire. The participants agreed that:

> The Company ***must***: Use existing demand response resources when possible. This includes using, to the extent possible, current demand response equipment owned or available to Idaho Power and participating demand response customers, which currently represents approximately 400 megawatts of potential demand response capacity.

Settlement Agreement, p. 3 (emphasis added). As described in Staff's Comments in Case No. IPC-E-13-14, the "resource-based value calculation combined with cost savings and program modification helps the Settlement *preserve previous investments in a valuable DR resource while limiting costs in years when it is not needed to meet load*." Staff DR Comments, p. 7 (emphasis added). As Staff correctly pointed out, the value calculation was intended to allow the Company to incur program costs even when such costs were not justified by the IRP. The value calculation was not intended to create a limit on participation or capacity.

Within each program description in the Settlement Agreement, the parties described how existing, and in some cases new, participants would be included in the programs going forward. The parties agreed early on that participation should not be unnecessarily limited and that the Company would utilize its "participating demand response customers." Settlement Agreement, p. 3. For the A/C Cool Credit program, the parties agreed that existing participants will be allowed to remain in the program, new participants will be allowed to join, and, in certain limited circumstances, the Company will contact customers to inquire about participation. Settlement Agreement, p. 5. For the Irrigation Peak Rewards program, participants are limited to past program participants with an active, working load control device. Settlement Agreement, p. 6. For the FlexPeak Management program, Idaho Power will not actively seek to expand the capacity. Settlement Agreement, p. 7. In no case does the Settlement Agreement allow Idaho Power to turn away existing program participants. In no event does the Settlement Agreement intend or imply a ***limitation of DR capacity*** based upon the 170 MW SCCT used to calculate the ***value*** of DR programs.

Because participation is not limited and because the Company must use existing DR resources when possible, the Company is required to accept up to 2012 participation levels, which is approximately 440 MW of DR. Staff alleges that attrition will substantially reduce the program sizes and capacity that the Company may receive. Idaho Power also believes that some unknown level of attrition will likely occur for each program. However, under the terms of the Settlement Agreement, Idaho Power must accept up to 440 MW of DR capacity if program participants choose to participate or any

new A/C Cool Credit participants wish to sign up at the programs' current incentive amounts.

B. Staff's Assumption Limiting DR Capacity to Only 170 MW Is Not Consistent with Idaho Power's 2013 IRP.

It is reasonable to include DR in the amounts identified in the Settlement Agreement and analyzed in the 2013 IRP for the Company's capacity deficiency determination for avoided cost rates. The Company's 2013 IRP utilizes DR up to 400 MW to meet all identified capacity deficits up to July 2021. As stated above, the Settlement Agreement requires the Company to accept all DR up to 2012 levels. Historical DR peak reduction capacity levels reported in the 2013 IRP are 336 MW for 2010, 403 MW for 2011, and 438 MW for 2012. 2013 IRP, p. 40. The preferred resource portfolio from the 2013 IRP relies primarily upon the Boardman to Hemingway ("B2H") transmission line with associated market purchases as the major resource acquisition to cost-effectively meet the Company's service obligations. 2013 IRP, p. 8. The preferred resource portfolio assumes an expected operational date of B2H as 2018. *Id.*

Because of delays in the ongoing required state and federal permitting processes for the B2H line, the Company recently announced that the operational date for B2H will be no sooner than 2020. Attachment 1 hereto contains the updated load and resource balance that was the basis for Table 3 in Idaho Power's Application in this proceeding and shows the inclusion of 440 MW of DR, which eliminates summer deficits through July 2020. The amount of DR begins at 30 MW in the summer of 2014 and gradually increases to 440 MW in the summer of 2021, which is the first summer the DR programs are not able to eliminate the entire deficit; i.e., the first deficit year. Just as

the preferred resource portfolio relied upon contributions from DR to meet peak capacity deficiencies prior to B2H becoming operational, the first resource portfolio that considers resource options without the addition of B2H meets all near-term, peak-hour capacity deficiencies with DR, up to 400 MW. *See* 2013 IRP, p. 91, Resource Portfolio 3. Resource Portfolio 3 considers the Company's resource portfolio without the addition of the B2H line, and includes DR up to 400 MW. This resource portfolio meets all identified capacity deficits to July 2021. If DR were limited to the 170 MW suggested by Staff, resulting in a first deficit year of 2016, the Company would have to presently be developing the next combined- or simple-cycle combustion turbine in order to have it operational to meet the 2016 deficit. However, the Company's IRP considered the alternative that B2H would not be on-line when anticipated and, in those alternatives, the Company's IRP calls for meeting those deficiencies with DR. Idaho Power's customers have borne the costs associated with developing the Company's DR programs and to ignore the past proven capabilities of these programs would be incorrect.

Staff, without analysis or basis, determines that Idaho Power's DR programs will shrink from approximately 440 MW to 170 MW as a result of the reduced incentives agreed upon in the Settlement Agreement. Staff Comments, p. 6. A reduction in the amount of DR was anticipated in the Settlement Agreement due to a current lack of need for the amount of DR that had been attained in the past. Although the Company has not projected what level of attrition will occur, the Company believes Staff is overestimating the amount of expected attrition for all three demand response programs. Even with some level of attrition, because the capacity deficiencies start at

approximately 30 MW and gradually ramp up past 440 MW in 2021, some level of attrition from the 438 MW acquired from DR in 2012, will still enable the deficits to be met, and for the DR programs to ramp up over time accordingly. It is entirely reasonable to assume that DR will be acquired at levels up to those achieved in prior years, and a chance that participation may grow. The Settlement Agreement requires Idaho Power to accept levels up to those of past years and also requires Idaho Power to accept new participants in the A/C Cool Credit program. As customer load continues to grow and the need for increasing amount of DR returns, the Company anticipates incentive payments may need to be adjusted to attain program participation levels experienced in the past. This was contemplated in the DR workshops and Settlement Agreement and demonstrates the flexibility the DR programs are able to provide.

Staff alleges that capacity of the Irrigation Peak Rewards program participation will fall from 320 MW to 110 MW. Staff provides no analysis to support this claim and fails to consider that the irrigation customers were represented and agreed to the incentive levels set out in the Settlement Agreement. Staff alleges that the irrigators repeatedly voiced concerns about the incentive reduction in the DR workshops. Idaho Power acknowledges that the irrigators were concerned about a reduction in the program incentive. However, after such concerns were voiced, the irrigators, Idaho Power, Staff, and others reached agreement on appropriate incentive amounts as evidenced by their support of the Settlement Agreement. After signing, no such representations were made.

While Staff acknowledges that the exact capacity of Idaho Power's DR programs is unknown, it continues to assert that the Company will experience a reduction in

capacity from 440 MW to 170 MW, shrinking to 39 percent of the programs' former size. Idaho Power believes that the terms set forth in the Settlement Agreement that maintain customer participation and infrastructure, and which relied upon agreement from representatives of customers will prevent such a drastic decrease in the size of its DR capacity.

Furthermore, the Settlement Agreement provides flexibility to the Company in years where the IRP demonstrates a need for increased demand response capacity. The Company must "reevaluate the value calculation as the IRP changes." Settlement Agreement, p. 3. The Commission acknowledged this flexibility in its order approving the Settlement Agreement, encouraging the Company to "continue evaluating opportunities associated with DR programs on an ongoing basis." Order No. 32923, p. 7.

Staff was highly critical of Idaho Power's responses to discovery questions posed by Staff in this matter stating, "In multiple responses, Idaho Power emphasized that the 'Company believes that is a reasonable assumption that it can satisfy the deficit of 30 Megawatts ("MW") in 2014 . . . with its existing demand response programs if necessary.'" Staff Comments, p. 6. Staff further states that it "does not believe that satisfying a deficit of 30 MW in the first year of a 20-year planning period is sufficient evidence to justify including 440 MW of demand response in each year of the planning period." *Id.* Idaho Power's answers to discovery questions quoted by Staff above were in direct response to Staff questions that asked about the level of DR the Company expected to acquire ***for 2014***. Idaho Power was answering the question asked in reference to the reasonable assumption that it can satisfy the 30 MW deficit in 2014 with

existing DR. However, just as it is reasonable to expect that a 30 MW deficit in 2014 will be met by existing DR, it is reasonable to expect that the increasing deficits through 2021 will be met by the existing DR of up to 440 MW, which is what Idaho Power is required to accept pursuant to the Settlement Agreement. An alternative resource portfolio that meets all capacity deficits through 2021 with up to 400 MW of DR was analyzed and included in the Company's acknowledged 2013 IRP. In this case, the Company provided updated 2013 IRP identified capacity deficits with the approved update to the load and natural gas forecasts, as well as updated contracts for use in the avoided cost rate methodologies—and included the additional 440 MW of DR as provided by the Settlement Agreement and as analyzed in the Company's accepted 2013 IRP. Staff's arbitrary limitation of DR to 170 MW is not reasonable or supported by the IRP and Settlement Agreement.

III. CONCLUSION

Idaho Power respectfully requests that the Commission issue an order approving the capacity deficiency period shown in Table 3 of Idaho Power's Application, with a first deficit occurring in July 2021. As discussed above, Staff's assumption limiting DR capacity to only 170 MW is not supported by the Settlement Agreement, or any other analysis. Idaho Power's inclusion of up to 440 MW of DR is consistent with the Settlement Agreement's requirement that Idaho Power accept all existing, and some new, demand response participants up to 2012 levels (which was 438 MW). It is also consistent with the preferred and alternative resource portfolios in the 2013 IRP, which utilizes DR to meet all identified capacity deficiencies until the B2H transmission line can be completed.

The purpose of this docket is to establish, outside of the IRP, the capacity deficiency utilized for avoided cost PURPA pricing. With this purpose in mind, any PURPA contracts entered into will lock in this capacity deficiency into its avoided cost rates for the next 20 years, and cannot subsequently be changed. The effect of arbitrarily limiting DR to 170 MW is to increase the avoided cost of capacity payments made in any PURPA contracts, and to lock that higher payment in for the next 20 years with no ability to change it, resulting in customers paying more than they should for these contracts. Even if the next IRP analysis, or the continued operation of the DR programs, shows that all capacity deficits are met through 2021 or beyond, the PURPA contracts will have locked in capacity payments for 20 years based upon the limitation of 170 MW of DR and a resulting capacity deficit that occurs at least five years sooner than the reasonable analysis and requirements of the Settlement Agreement and 2013 IRP indicate. Idaho Power respectfully requests that the Commission issue an order approving the capacity deficiency period shown in Table 3 of Idaho Power's Application, with a first deficit occurring in July 2021.

Respectfully submitted this 14th day March 2014.

DONOVAN E. WALKER
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 14th day of March 2014 I served a true and correct copy of IDAHO POWER COMPANY'S REPLY COMMENTS upon the following named parties by the method indicated below, and addressed to the following:

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Christa Bearry, Legal Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-21

IDAHO POWER COMPANY

ATTACHMENT 1

Peak-hour Load and Resource Balance

	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Load Forecast (95th% w/ no DSM)	(2,557)	(2,399)	(2,073)	(1,989)	(2,675)	(3,250)	(3,474)	(3,101)	(2,790)	(2,059)	(2,268)	(2,720)
Existing DSM (Energy Efficiency)	14	14	14	15	16	16	16	16	15	14	14	14
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,543)	(2,385)	(2,059)	(1,974)	(2,659)	(3,264)	(3,488)	(3,115)	(2,774)	(2,045)	(2,254)	(2,706)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	30	30	30	0	0	0	0
Peak-Hour Forecast w/DR	(2,543)	(2,385)	(2,059)	(1,974)	(2,659)	(3,234)	(3,458)	(3,085)	(2,774)	(2,045)	(2,254)	(2,706)
Existing Resources												
Coal	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	852	1,078	1,017	1,061	1,132	1,024	914	874	758	880	673	935
Hydro (90th%)—Other	244	245	224	243	343	356	303	269	255	248	238	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,097	1,323	1,241	1,304	1,475	1,380	1,265	1,143	1,012	1,129	911	1,179
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange - Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
Total Power Purchase Agreements	29	40	30	27	42	43	41	40	39	27	23	39
Firm Pacific NW Import Capability	0	0	0	0	230	352	237	277	113	0	0	1
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,934	3,173	3,084	3,117	3,631	3,663	3,439	3,350	3,041	3,002	2,752	3,030
Monthly Surplus/Deficit	0	0	0	0	0	0	(19)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	1	4	6	6	5	3	0	0	0
Commercial	13	13	13	13	13	13	13	13	13	13	13	13
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Total New DSM Peak Reduction	13	13	13	14	17	19	20	19	16	14	13	13
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Load Forecast (95th% w/ no DSM)	(2,634)	(2,453)	(2,146)	(2,062)	(2,732)	(3,266)	(3,491)	(3,111)	(2,864)	(2,095)	(2,309)	(2,762)
Existing DSM (Energy Efficiency)	21	21	21	22	24	24	24	23	23	22	21	21
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,613)	(2,432)	(2,125)	(2,040)	(2,708)	(3,337)	(3,562)	(3,183)	(2,841)	(2,074)	(2,288)	(2,741)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	95	95	95	0	0	0	0
Peak-Hour Forecast w/DR	(2,613)	(2,432)	(2,125)	(2,040)	(2,708)	(3,242)	(3,467)	(3,088)	(2,841)	(2,074)	(2,288)	(2,741)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	855	1,080	1,029	1,062	1,134	1,025	914	873	756	886	672	937
Hydro (90th%)—Other	244	246	231	245	352	365	304	272	255	252	241	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,100	1,326	1,260	1,307	1,487	1,390	1,266	1,145	1,011	1,138	913	1,181
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange - Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
Total Power Purchase Agreements	29	40	30	27	42	43	41	40	39	27	23	39
Firm Pacific NW Import Capability	0	0	0	0	276	342	237	274	147	0	0	15
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,937	3,176	3,103	3,178	3,689	3,663	3,439	3,348	3,074	3,011	2,753	3,046
Monthly Surplus/Deficit	0	0	0	0	0	0	(28)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	2	6	8	8	7	4	1	0	0
Commercial	19	19	19	19	19	20	20	20	19	19	19	19
Residential	1	1	1	1	1	1	1	1	1	1	1	1
Total New DSM Peak Reduction	20	20	20	21	26	28	29	27	23	20	20	20
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Load Forecast (95th% w/ no DSM)	(2,672)	(2,476)	(2,176)	(2,099)	(2,785)	(3,215)	(3,448)	(3,058)	(2,931)	(2,132)	(2,351)	(2,803)
Existing DSM (Energy Efficiency)	26	26	26	27	29	30	30	29	28	26	26	26
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,646)	(2,450)	(2,150)	(2,072)	(2,755)	(3,401)	(3,634)	(3,244)	(2,903)	(2,106)	(2,325)	(2,777)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	215	215	215	0	0	0	0
Peak-Hour Forecast w/DR	(2,646)	(2,450)	(2,150)	(2,072)	(2,755)	(3,186)	(3,419)	(3,029)	(2,903)	(2,106)	(2,325)	(2,777)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	854	1,082	1,026	1,061	1,133	1,022	911	797	753	881	672	934
Hydro (90th%)—Other	244	248	231	244	353	365	303	233	256	252	241	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,098	1,329	1,257	1,305	1,485	1,388	1,215	1,030	1,009	1,133	913	1,178
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	314	342	237	272	178	0	0	34
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,931	3,176	3,106	3,185	3,662	3,654	3,382	3,227	3,100	3,015	2,767	3,059
Monthly Surplus/Deficit	0	0	0	0	0	0	(36)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	2	7	9	10	8	4	1	0	0
Commercial	25	24	24	24	25	25	25	25	24	24	24	24
Residential	2	2	2	2	2	2	2	2	2	2	2	2
Total New DSM Peak Reduction	27	26	26	28	33	36	37	35	31	27	26	26
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Load Forecast (95th% w/ no DSM)	(2,705)	(2,507)	(2,201)	(2,123)	(2,829)	(3,215)	(3,460)	(3,054)	(2,986)	(2,160)	(2,379)	(2,827)
Existing DSM (Energy Efficiency)	30	30	30	31	34	35	35	34	33	30	30	30
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,675)	(2,477)	(2,172)	(2,092)	(2,795)	(3,455)	(3,700)	(3,295)	(2,953)	(2,130)	(2,349)	(2,797)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	275	275	275	0	0	0	0
Peak-Hour Forecast w/DR	(2,675)	(2,477)	(2,172)	(2,092)	(2,795)	(3,180)	(3,425)	(3,020)	(2,953)	(2,130)	(2,349)	(2,797)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	852	1,080	1,023	1,060	1,132	1,020	909	794	750	875	673	932
Hydro (90th%)—Other	244	246	231	244	350	363	303	232	256	252	240	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,096	1,326	1,254	1,304	1,482	1,383	1,212	1,026	1,006	1,126	914	1,176
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	359	347	237	269	219	0	0	61
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,929	3,173	3,104	3,184	3,762	3,654	3,380	3,221	3,137	3,009	2,767	3,084
Monthly Surplus/Deficit	0	0	0	0	0	0	(45)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	2	8	11	11	9	5	1	0	0
Commercial	29	29	29	29	30	30	30	30	29	29	29	30
Residential	4	4	4	4	4	3	3	3	4	4	4	4
Total New DSM Peak Reduction	33	33	33	35	41	44	45	43	38	34	33	33
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	(0)	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Load Forecast (95th% w/ no DSM)	(2,711)	(2,513)	(2,199)	(2,114)	(2,859)	(3,525)	(3,791)	(3,362)	(3,017)	(2,175)	(2,377)	(2,843)
Existing DSM (Energy Efficiency)	34	34	34	35	39	40	40	39	37	34	34	34
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,677)	(2,480)	(2,165)	(2,078)	(2,820)	(3,485)	(3,751)	(3,323)	(2,980)	(2,141)	(2,343)	(2,809)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	320	320	320	0	0	0	0
Peak-Hour Forecast w/DR	(2,677)	(2,480)	(2,165)	(2,078)	(2,820)	(3,165)	(3,431)	(3,003)	(2,980)	(2,141)	(2,343)	(2,809)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	850	1,073	1,013	1,058	1,131	1,017	907	790	747	870	673	930
Hydro (90th%)—Other	243	245	230	244	347	358	302	231	255	250	240	243
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,093	1,318	1,243	1,303	1,478	1,376	1,209	1,021	1,002	1,121	912	1,173
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	385	342	237	267	257	0	0	86
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,927	3,164	3,093	3,183	3,783	3,642	3,377	3,214	3,171	3,003	2,766	3,106
Monthly Surplus/Deficit	0	0	0	0	0	0	(55)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	2	9	12	13	11	6	1	0	0
Commercial	35	35	35	35	35	36	36	36	35	35	35	35
Residential	7	7	7	7	7	6	6	6	7	7	7	7
Total New DSM Peak Reduction	42	42	41	44	51	55	55	53	48	42	42	42
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Load Forecast (95th% w/ no DSM)	(2,740)	(2,535)	(2,222)	(2,136)	(2,893)	(3,562)	(3,850)	(3,399)	(3,056)	(2,198)	(2,402)	(2,870)
Existing DSM (Energy Efficiency)	37	37	37	39	44	45	45	44	41	38	37	37
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,703)	(2,498)	(2,185)	(2,097)	(2,849)	(3,517)	(3,805)	(3,356)	(3,015)	(2,160)	(2,365)	(2,832)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	365	365	365	0	0	0	0
Peak-Hour Forecast w/DR	(2,703)	(2,498)	(2,185)	(2,097)	(2,849)	(3,152)	(3,440)	(2,991)	(3,015)	(2,160)	(2,365)	(2,832)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	848	1,071	1,007	1,057	1,130	1,015	905	787	744	862	674	927
Hydro (90th%)—Other	243	245	230	243	344	355	302	231	229	250	238	242
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,091	1,316	1,237	1,300	1,473	1,371	1,208	1,018	973	1,112	912	1,171
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	384	342	237	265	270	0	0	111
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,924	3,162	3,087	3,180	3,720	3,637	3,376	3,208	3,155	2,994	2,765	3,129
Monthly Surplus/Deficit	0	0	0	0	0	0	(64)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	3	10	14	15	12	7	1	0	0
Commercial	40	39	40	39	40	41	41	41	40	39	40	40
Residential	10	10	10	10	10	9	9	9	10	10	10	10
Total New DSM Peak Reduction	49	49	49	52	60	64	65	62	56	50	49	50
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Load Forecast (95th% w/ no DSM)	(2,769)	(2,555)	(2,247)	(2,162)	(2,927)	(3,599)	(3,910)	(3,436)	(3,093)	(2,220)	(2,430)	(2,898)
Existing DSM (Energy Efficiency)	42	42	42	44	49	50	51	49	46	43	42	42
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,727)	(2,513)	(2,205)	(2,118)	(2,877)	(3,549)	(3,859)	(3,387)	(3,047)	(2,177)	(2,388)	(2,856)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	415	415	415	0	0	0	0
Peak-Hour Forecast w/DR	(2,727)	(2,513)	(2,205)	(2,118)	(2,877)	(3,134)	(3,444)	(2,972)	(3,047)	(2,177)	(2,388)	(2,856)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	843	1,068	1,005	1,056	1,128	1,013	902	783	741	853	673	927
Hydro (90th%)—Other	243	243	230	243	341	353	301	230	228	250	237	241
Shoshone Falls Upgrade (90th%)	3	2	0	0	9	11	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,088	1,313	1,235	1,298	1,479	1,377	1,205	1,013	968	1,103	910	1,170
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	383	342	237	262	269	0	4	139
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,922	3,160	3,085	3,178	3,782	3,643	3,373	3,201	3,149	2,985	2,767	3,156
Monthly Surplus/Deficit	0	0	0	0	0	0	(71)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	3	12	16	17	14	8	1	0	0
Commercial	45	45	45	45	46	47	47	47	45	45	46	45
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM Peak Reduction	54	54	54	57	66	71	72	69	62	55	55	54
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	0	0	0	0	0	0

Peak-hour Load and Resource Balance

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Load Forecast (95th% w/ no DSM)	(2,800)	(2,581)	(2,271)	(2,184)	(2,967)	(3,647)	(3,976)	(3,483)	(3,138)	(2,245)	(2,457)	(2,929)
Existing DSM (Energy Efficiency)	45	45	45	48	54	55	56	54	51	46	45	45
Peak-Hour Forecast w/ Energy Efficiency (October 2013 Update)	(2,754)	(2,536)	(2,226)	(2,137)	(2,913)	(3,592)	(3,921)	(3,429)	(3,087)	(2,199)	(2,411)	(2,884)
Existing Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response (up to 440 MW)	0	0	0	0	0	440	440	440	0	0	0	0
Peak-Hour Forecast w/DR	(2,754)	(2,536)	(2,226)	(2,137)	(2,913)	(3,152)	(3,481)	(2,989)	(3,087)	(2,199)	(2,411)	(2,884)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	841	1,066	1,004	1,054	1,127	1,009	899	779	737	840	674	923
Hydro (90th%)—Other	242	243	229	243	341	328	300	229	227	248	235	241
Shoshone Falls Upgrade (90th%)	3	2	0	0	8	10	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,086	1,311	1,233	1,297	1,476	1,347	1,202	1,008	964	1,089	909	1,166
CSPP (PURPA) (September 2013 Update)	70	71	74	104	145	149	156	150	137	107	78	71
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	87	0	0	0	434	395	290	313	320	0	83	225
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,949	3,100	3,026	3,120	3,773	3,609	3,365	3,189	3,138	2,914	2,788	3,180
Monthly Surplus/Deficit	0	0	0	0	0	0	(116)	0	0	0	0	0
2013 IRP DSM (Energy Efficiency)												
Irrigation	0	0	0	4	13	19	20	16	9	2	0	0
Commercial	51	51	50	51	52	53	53	53	51	51	51	51
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM Peak Reduction	60	60	60	64	74	80	80	77	69	62	60	60
Remaining Monthly Surplus/Deficit (CAPACITY DEFICIENCY)	0	0	0	0	0	0	(36)	0	0	0	0	0